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Simulation of Early-Time Response of Single-Well Steam Assisted Gravity Drainage (SW-SAGD)

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Abstract

Steam assisted gravity drainage (SAGD) is an effective method of producing heavy oil and bitumen. In a typical SAGD approach, steam is injected into a horizontal well located directly above a horizontal producer. A steam chamber grows around the injection well and helps displace heated oil toward the production well. Single-well (SW) SAGD attempts to create a similar process using only one horizontal well. This may include steam injection from the toe of the horizontal well with production at the heel. Obvious advantages of SW-SAGD include cost savings and utility in relatively thin reservoirs. However, the process is technically challenging.

To improve early-time response of SW-SAGD, it is necessary to heat the near-wellbore area to reduce oil viscosity and allow gravity drainage to take place. Since project economics are sensitive to early production response, we are interested in optimizing the start-up procedure.

An investigation of early-time processes to improve reservoir heating will be discussed. We performed a numerical simulation study of combinations of cyclic steam injection and steam circulation prior to SAGD in an effort to better understand and improve early-time response. Results from this study, including cumulative recoveries, temperature distributions, and production rates display variances within the methods. It is found that cycling steaming of the reservoir prior to SAGD offers the most favorable option for heating the near-wellbore area and creating conditions that will improve initial SAGD response.

Introduction

Background. Steam assisted gravity drainage maximizes the role of gravity forces during steam flooding of heavy oils. Generally, it is applied with a pair of horizontal wells. Single-well steam assisted gravity drainage is similar in concept to conventional SAGD. As steam enters the reservoir, it heats up the reservoir fluids and surrounding rock, allowing hot oil and condensed water to drain though the force of gravity to a production well at the bottom of the formation. Heat is transferred by conduction, convection, and latent heat of the steam. In conventional SAGD, steam is typically injected through a horizontal injection well placed directly above a horizontal production well. Thus, a steam chamber forms directly above the production well. In SW-SAGD, we attempt to create the same recovery mechanism through the use of a single horizontal well. In a typical case, steam is injected at the toe of the well, while hot reservoir fluids are produced at the heel of the well.

In a reservoir where cold oil is very viscous and will not flow easily, initial production rates via SAGD are very low. Conceptually this makes sense when the SAGD process is visualized. In a strict definition of SAGD, steam only enters the reservoir to fill a void space caused by produced oil. However, if the oil is cold and will not gravity drain into the wellbore at appreciable rates, we must heat the oil to reduce the viscosity so that it will flow. Therefore, initial heating of the area around the wellbore is required so that SAGD can take place.

After SAGD is initiated, a steam chamber will grow in the reservoir. Butler notes that the steam chamber will initially grow upward to the top of the reservoir and then begin extending horizontally.[1] At the steam-chamber boundary, steam condenses to water as heat is transferred to the oil. Condensed water and hot oil flow along the steam chamber to the production well.[1]

Joshi found that under various injection/production well configurations, the steam chamber will eventually grow to cover a majority of the reservoir and the recovery efficiencies will be very good in all cases.[2] Therefore, we expect that early-time production results from SW-SAGD may vary from the conventional approach, but at late times we expect similar recovery efficiencies. Additionally, Oballa and Buchanan[3] simulated various scenarios to evaluate the difference between cyclic steam injection and SAGD. They focused, partially, on the interactions between the reservoir, the well completion, and the recovery of oil. It was concluded that the drainage process may be feasible provided that a proper operating strategy is identified.

Very few of the field tests of SW-SAGD are documented in the literature; however an overview of the completion strategy and some typical results is given by Falk *et al*[4]. For example, a roughly 850 m long well in a section of the Cactus Lake Field, Alberta Canada with 12 to 16 m of net pay was installed to produce 12 °API gravity oil. The reservoir is a clean, unconsolidated, 3400 md permeability sand. Oil production response to steam was slow and gradually increased to more than 100 m^3/d. The cumulative steam-oil ratio was between 1 and 1.5 for the roughly one-half year of reported data.

One advantage of SW-SAGD, as in the Cactus Lake example, is that it may allow us to apply SAGD to thinner reservoirs where it is not possible to drill two vertically spaced horizontal wells[4]. Furthermore, cost savings associated with drilling one horizontal well rather than two are substantial.

Problem Definition. This paper is focused on understanding operating conditions to improve the crucial early-time performance of SW-SAGD. This relates directly to understanding methods of heating the near-wellbore area at early-time. The central idea used throughout this paper is that the near-well region must be heated rapidly and efficiently for significant early-time response.

Methodology. We gained an understanding of early-time performance through building and comparing various computer simulations. The early-time processes examined include cyclic steaming, steam circulating, and an extreme pressure differential between the injector and producer sections of the well. Each initial operating period was followed by SAGD. Computer Modeling Groups's (CMG) STARS thermal simulator is used to perform the work.

Model Description

The base case is STARS example *sthrw009.dat* released with Version 98.01. It represents a typical Alberta reservoir[5]. The operating conditions and well completion are modified to develop additional cases.

Grid System. Fig. 1 displays cross-sections along the length of the well (Fig. 1a) and perpendicular to the well (Fig. 1b). The grid system is Cartesian with local grid refinement immediately around the 800 m long well. An element of symmetry, with one boundary lying along the wellbore, is used to represent the reservoir volume. We assume that wells will be developed in multiple patterns and thus all boundaries are no flux. The single horizontal well is modeled using two individual discretized wellbores, each equal in length and placed directly end to end. This gives us freedom to explore various completion strategies and operating conditions. **Table 1** lists the exact dimensions of the reservoir model, grid-block information, and reservoir properties. Initially, the average reservoir pressure is 2,654 kPa, the pressure distribution is hydrostatic, and the reservoir temperature is 16 °C.

Rock Properties. Reservoir properties are also given in Table 1. **Figs. 2 and 3** display graphically the water-oil relative permeability and gas-liquid relative permeability curves, respectively. **Table 1** displays the porosity and initial saturations of the reservoir. The horizontal permeability, K_h, is 3400 md, whereas the vertical permeability, K_v, is 680 md. Hence, the ratio K_h:K_v is about 5 to 1. The homogeneous porosity is 33%.

Fluid Properties. A live, black-oil model is used. The initial oil phase is made up of 90% by mole oil component and 10% gas component. Oil viscosity at the initial reservoir temperature is 4000 mPa-s. **Figure. 4** displays the viscosity versus temperature relationship. An increase of oil temperature to 100 °C decreases the oil viscosity to 30 mPa-s.

Operating Conditions. Table 2 lists the operating constraints for the four base cases created to explore a range of early-time procedures. Briefly the cases represent SAGD operating conditions, extreme pressure differential conditions where steam is injected near the fracturing or parting pressure, cyclic steam injection, and steam circulation through the well. Arbitrarily, 100 d was chosen as the duration of attempts to heat the near-well region. In all cases, SAGD conditions follow. Each of the constraints will be discussed in more detail in the *Results and Discussion* Sections.

Results

Overview. In an attempt to heat the near-wellbore area and improve the initial production response of SAGD, we combined the operating conditions displayed in Table 2 into the various cases displayed in **Table 3**. There are four operating condition scenarios and seven cases overall. In each case, an initial preheating phase precedes SAGD.

Fig. 5 displays recovery factor versus time curves for each case. Case 1 represents a base case in which SAGD was initiated from the beginning without a preheating phase. This case produced the lowest percent recovery curve. It is obvious from the curves that it is possible to improve drastically initial production response. In general, cyclic steaming leads to most rapid oil recovery. We discuss Cases 1—Continuous SAGD, 2—Extreme Pressure Differential, and 5—Cyclic Steam Injection in more detail to gain insight into the early-time behavior. The late-time production behavior is also examined.

Case 2 is a modified form of steam circulation in the well. We did not simulate true steam circulation where steam exiting the tubing is allowed only to flow in the well before it is produced. A true circulating case in which the near-wellbore area is heated only by conduction would be inefficient, and the other techniques that we explore present better options. Circulation here is similar to the SAGD case: steam may replace oil volume in the reservoir when oil is produced.

Hence, our "circulating" condition is somewhat of a misnomer.

Case 1, Continuous SAGD. In Case 1 we immediately operate at SAGD conditions and do not include a preheat phase. In this case, and the cases to follow, production rates, well pressures and temperature profiles around the well are examined. **Fig. 6** displays the injection and production curves for Case 1. The darkest curve in Fig. 6 represents the oil production rate. As expected, the initial oil rate is low, but increases with time as a steam chamber slowly develops and more oil is heated. Oil production peaks at roughly 80 m^3/day

Note that our "SAGD" case is actually a combination of SAGD and pressure draw-down. Production well conditions are such that reservoir pressure must decline. It is clear from the similarity between the steam injection rate and water production rate in Fig. 6 that steam short-circuits from the injection well to the production well and the contact time for steam with the reservoir is short. Recall that in our model we represent the horizontal well with two separate sections placed end-to end. The pressure differential between the wells and the proximity of "injection" and "production" perforations causes steam to travel immediately the short distance through the reservoir from the injection well to the production well. Increasing the spacing between the injection and production points and/or reducing the pressure differential would certainly reduce the amount of short-circuiting. Albeit inefficiently, a steam chamber is created within the reservoir as heated oil drains to the production well and steam migrates up to fill the void space. Optimizing the well spacing and pressure drawdown represents another interesting problem that we are currently addressing.

Fig. 7 displays bottom-hole pressure curves for injection and production in Case 1. A large pressure differential of about 2000 kPa exists between the two sections of the well. Over time, the reservoir pressure decreases because we produce more fluids than we inject. This also causes the injection pressure to decrease.

Fig. 8 displays a temperature profile at 100 days for Case 1. Light shading corresponds to high temperature and dark shading to low temperature. At late times, a large steam chamber grows in the middle region of the system. At this point, however, the steam chamber is just beginning to grow above the short-circuiting area between the injection and production sections. We will see that the same profile at similar relative times in the other cases displays a much larger heated area. It is important to maximize the amount of net heat injection into the reservoir at early times, therefore, maximizing the size of the heated volume surrounding the wellbore.

Case 2, Extreme Pressure Differential Prior to SAGD. In the extreme pressure differential case we increase the injection rate constraint which thereby increases the pressure differential between the injection and production wells. **Fig. 9** displays the bottom-hole pressure versus time curves. For the first 100 d, steam is injected at roughly 7000 kPa forcing steam into the formation and increasing the average reservoir pressure. **Fig. 10** displays the production response for the extreme period in the first 100 days followed by SAGD operating conditions. Observing the oil rate in the first 100 days and comparing to Fig. 6, we see that the oil rate ramps up faster than Case 1. This is logical because Case 2 is an accelerated version of SAGD.

Fig. 9 also indicates that a very high injection bottom-hole pressure is obtained between 0 and 100 d of injection. High pressure results because the water production rate is substantially less than the steam injection rate, as shown in Fig. 10. Under the given conditions a limited amount of steam short-circuits, and an appreciable amount of steam enters the reservoir and increases the reservoir pressure.

If we view the oil production rate in Fig. 10 during and after the extreme period, it is obvious that we have improved response. Direct comparison of Cases 2 and 1 is somewhat misleading. Injection conditions have lead to high reservoir pressure at the beginning of SAGD, causing significant production through pressure depletion in addition to gravity drainage of heated reservoir heating fluids. A better comparison is the temperature profile along the length of the well displayed in **Fig. 11.** The profile represents a relative time similar to similar to the Case 1 profile, 100 days after SAGD inception. Again, light shading is high temperature and dark shading is low temperature. The profile for Case 2 is much more favorable. There is a larger heated area and the corresponding steam chamber is larger. The steam chamber forms in the middle of the well because pressure drawdown is large in this vicinity and in this region the steam flux into the reservoir is largest.

Case 5, One Cycle Prior to SAGD. Our cyclic case is very similar to typical cyclic operations common in many thermal recovery operations. We inject steam along the entire well for 50 days, let it soak for 10 days, then produce along the entire length of the well for 120 days. The injection and production profiles in **Fig. 12** summarize this cycle of steam injection, shut in, production.

Fig. 13 shows that the bottom-hole pressure increases to about 8000 kPa during the injection phase, but still remains within a feasible range. Because the oil is very viscous, this energy is rapidly depleted from the reservoir. From the oil production rate after the cycling period in Fig. 12, it is again obvious that we have improved SAGD response. The slow increase of production rate found in Case 1 is not evident here. The minimum production rate at roughly 200 d occurs because reservoir pressure is depleted somewhat following the cyclic period, as shown by the plot of well bottom hole pressure in Fig. 13. Again, the maximum oil production rate is about 80 m^3/day. In this case, the reservoir pressure at SAGD inception is similar to that in Case 1. Therefore we conclude that SAGD performs better because the near-wellbore area is heated, creating favorable SAGD conditions.

Fig. 14 displays the temperature profile at a relative time similar to the Case 1 profile, 120 days after SAGD inception. The temperature distribution is more uniform along the entire wellbore. In this case, a large steam chamber is growing in the middle of the reservoir.

Contrary to the extreme pressure differential and SAGD cases where short-circuiting caused much of the steam to exit the reservoir immediately, the cyclic case is more efficient. All of the injected steam enters the reservoir and heats the near-wellbore area. One consequence of this is the uniform temperature distribution along the entire wellbore. Because of the increased thermal efficiency of the cyclic process, it appears that this procedure is the most appealing method of initiating SAGD. In the scope of our research up to this point, we have not optimized the cyclic process. The problem of optimizing cycle times, operating conditions, and the number of cycles should be studied in more detail.

Discussion

The problem of improving early-time performance of SW-SAGD transforms, essentially, into a problem of heating rapidly the near-wellbore area to create conditions that allow gravity drainage of oil to take place. More specifically, in order for a steam chamber to grow, oil viscosity must be low enough so that fluid drains to the wellbore creating volume that steam can fill and thereby migrate upward in the reservoir. After the conditions necessary for gravity drainage of oil have been initiated by preheating, the SW-SAGD process allows for continuous steam chamber growth and oil production.

After comparing various simulation results, cyclic steam injection appears to be the most efficient method of heating the near-wellbore area. The problem of optimizing the early-time cyclic procedure should be further studied.

An important general observation is that regardless of the process, early-time procedures should be carried out to maximize steam injection and heat delivery to the reservoir. The goal of any early-time procedure should be to heat the near-wellbore area as uniformly as possible. This goal is easier to achieve when operating at a maximum steam temperature. Later in the SAGD process, pressure can be reduced to a target operating pressure which optimizes efficiency and production rate.

As a final observation, there are obvious factors that will improve or inhibit SW-SAGD performance. For example, lower viscosity will certainly improve response, as will higher permeability and system compressibility. Our model, however, represents a base case from which we draw general conclusions. The actual variance in performance due to varying reservoir parameters is an interesting problem that should be studied in more detail. A sensitivity analysis of reservoir properties should be performed.

Conclusions

A primary conclusion reached here is that to improve early-time performance of SW-SAGD, it is necessary to heat the near-wellbore region rapidly and uniformly to create conditions favorable to the SAGD process. Cyclic steaming, as a predecessor to SW-SAGD, represents the most thermally efficient early-time heating method. Uniform heating along the length of the wellbore appears achievable with cyclic steam injection. Regardless of the early-time process, it should be performed to provide maximum heat delivery to the reservoir.

Finally, despite different initial procedures, the oil production rates after several years of steam injection are all very similar.

Further Areas of Study

This paper presents qualitative ideas on how to improve early-time performance of SW-SAGD. An obvious extension of this work is to optimize each procedure using quantitative results such as net heat injection and steam-oil ratio. Beyond early-time performance, there are also interesting issues regarding the SAGD process and steam-chamber development. One issue that we are currently studying is the problem of maximizing steam chamber growth by optimizing the pressure differential and spacing between the injection and production portions of the well.

The following list displays ideas for future areas of study:

1. Optimize early-time performance with quantitative results such as net heat injection and steam-oil ratio.
2. Determine optimum pressure differential and spacing between injection and production points to maximize steam chamber growth.
3. Perform a sensitivity analysis and determine a range of reservoir parameters in which SW-SAGD represents an effective enhanced oil recovery technique. Example parameters include reservoir thickness, relative permeability, absolute permeability, etc.
4. Optimize the late time performance by studying target SAGD pressures that will decrease the volume of steam that must be injected while maintaining oil production rate.

References

1. Butler, R.M., Thermal Recovery of Oil and Bitumen, Englewood Cliffs, N.J.: Prentice Hall, 1991, pp. 285-359.
2. Joshi, S.D., “A Laboratory Study of Thermal Oil Recovery Using Horizontal Wells,” paper SPE/DOE 14916 presented at the 1986 SPE/DOE Fifth Symposium on Enhanced Oil Recovery held in Tulsa, OK, April 20-23.
3. Oballa, V., and Buchanan, W.L., “Single Horizontal Well in Thermal Recovery Processes,” paper SPE 37115 presented at the 1996 International Conference on Horizontal Well Technology, Calgary, Canada, Nov. 18-20.
4. Falk, K., Nzekwu, B., Karpuk, B, and Pelensky, P., “Concentric CT for single-well steam-assisted gravity drainage,” World Oil (July 1996), 85-95.
5. Computer Modeling Group, “STARS Version 98 User’s Guide,” Calgary, Alberta Canada, 1998.

Table 1 - Model Description

Grid System	
3D Cartesian System	
Hybrid Grid Surrounding Well	
Total Number of Blocks:	5,568
X-Dimension (m):	1,400
Y-Dimension (m):	80
Z-Dimension (m):	19.6
Well Length (m):	800
Reservoir Properties	
Initial Pressure (kPa):	2,654
Initial Temperature (C):	16
Initial So (%):	85
Initial Sw (%):	15
Rock Properties	
Porosity (%):	33
Kh (mD):	3,400
Kv (mD):	680
Relative Permeability	See Figs. 2, 3
Fluid Properties	
Live Oil	
Viscosity	See Fig. 4
Water, Oil, & Gas Components	
Initial Oil Phase Composition:	90% Oil, 10% Gas

Table 2 - Description of Operating Conditions

Property	Operating Condition			
	SAGD	Extreme Pressure Differential	Cyclic	Circulating
Steam Temp. (C):	295	295	295	295
Steam Pres. (kPa):	8014	8014	8014	8014
Injection Well Max Rate Constraint (m3/D):	200	600	300	300
Injection Well Max Pres. Constraint (kPa):	10,000	10,000	10,000	10,000
Production Well Max Rate Constraint (m3/D):	300	600	300	300
Production Well Minimum Pres. Constraint (kPa):	500	500	500	500

Table 3 - Description of Simulation Cases

Case	Description
1	SAGD Operating Conditions from Start
2	Extreme Pressure Differential Conditions for 100 d, Followed by SAGD Operating Conditions.
3	Circulate 100 d, Followed by SAGD Operating Conditions
4	Circulate 100 d, Followed by Extreme Pressured Differential Conditions for 100 d, Followed by SAGD Operating Conditions.
5	Cycle 1X, Followed by SAGD Operating Conditions
6	Cycle 2X, Followed by SAGD Operating Conditions
7	Cycle 3X, Followed by SAGD Operating Conditions

Fig. 1a - X-Y Cross-Section, Parallel to Wellbore

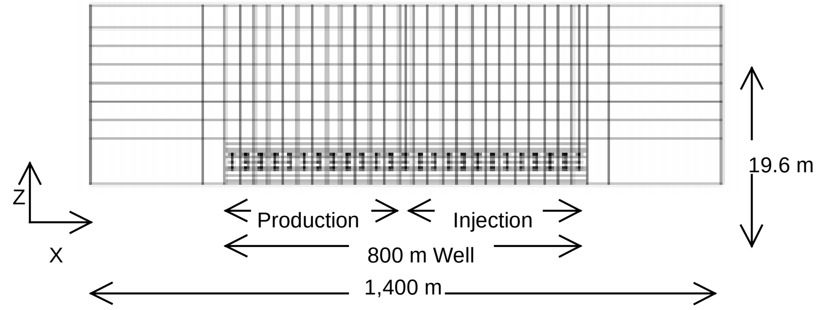

Fig. 1b - Y-Z Cross-Section, Perpendicular to Wellbore

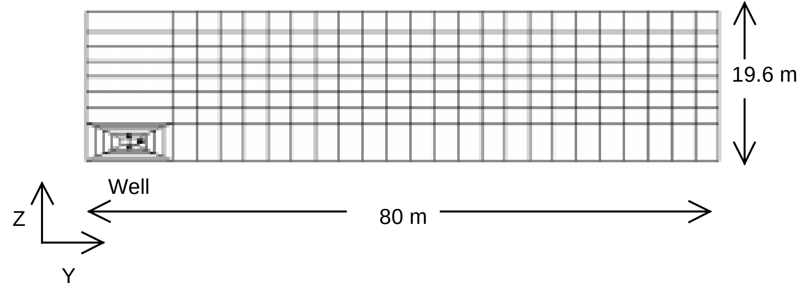

Fig. 1 - Visual Description of the Grid System

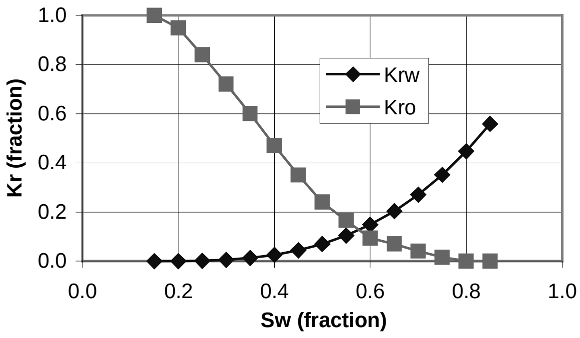

Fig. 2 - Water-Oil Relative Permeability Curve

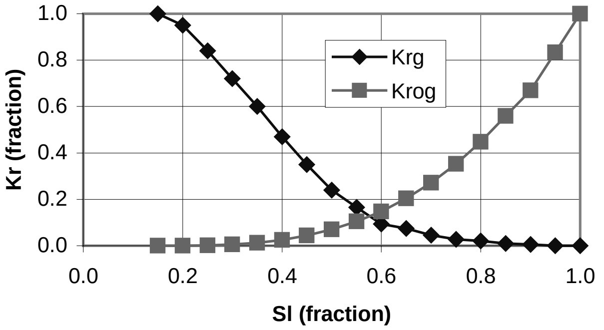

Fig. 3 - Gas-Liquid Relative Permeability

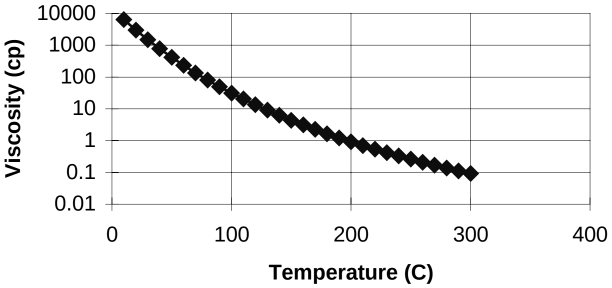

Fig. 4 - Viscosity/Temperature Relationship

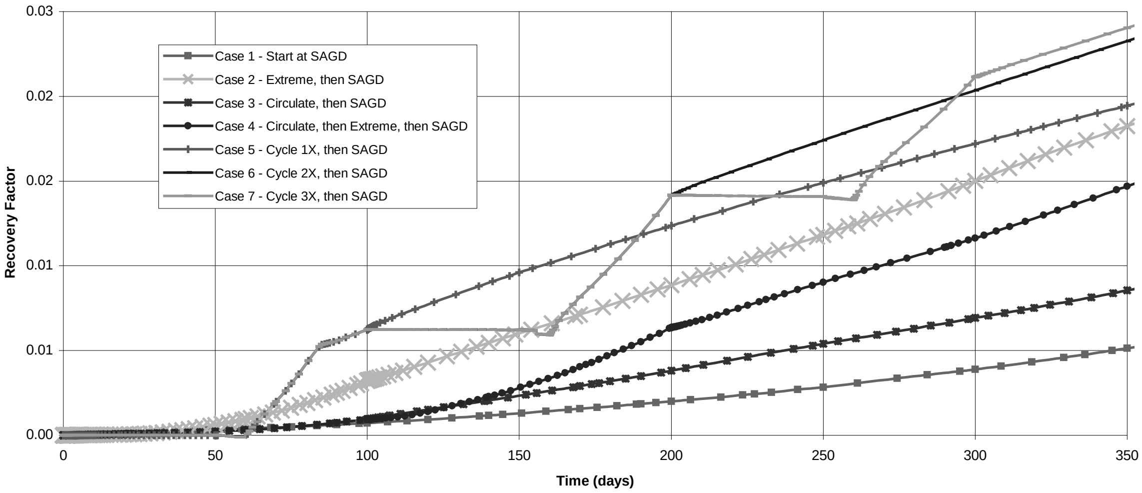

Fig. 5 - Recovery Factor vs. Time for All Cases

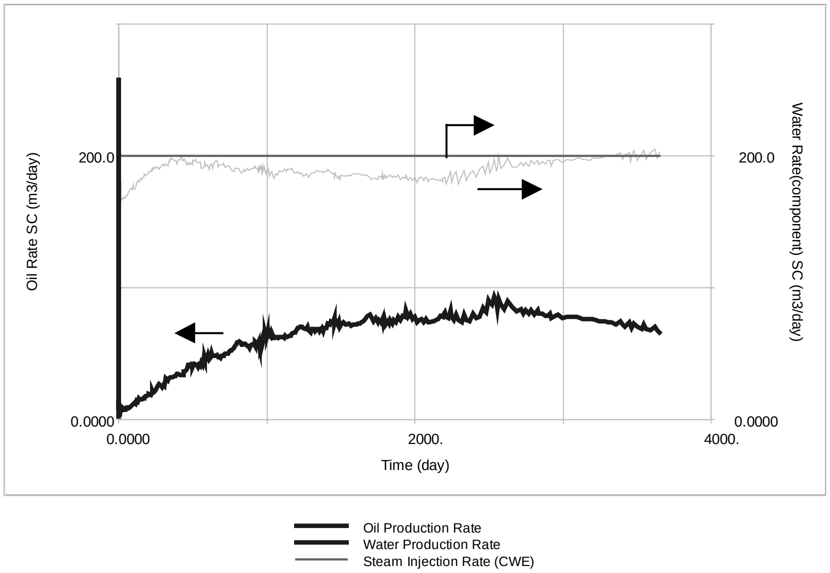

Fig. 6 - Production & Injection Rates vs. Time

Case 1, Continuous SAGD

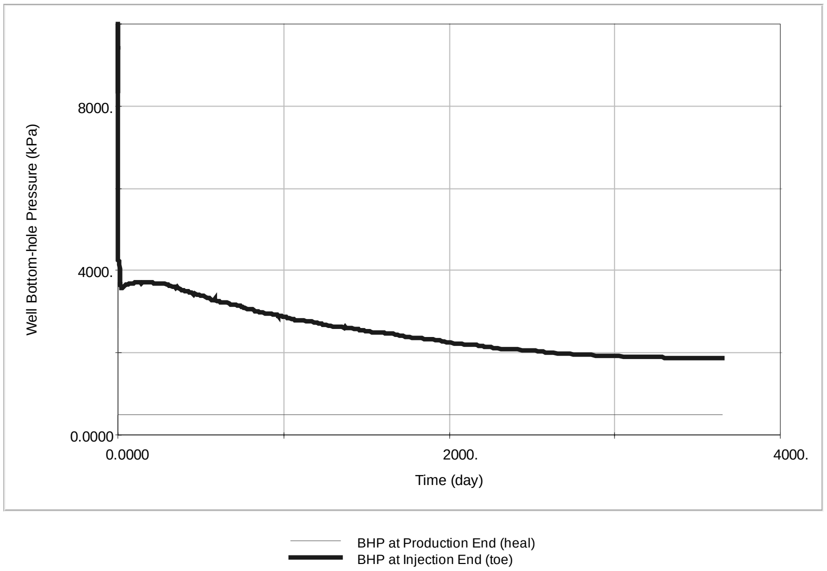

Fig. 7 - Well BHP vs. Time

Case 1, Continuous SAGD

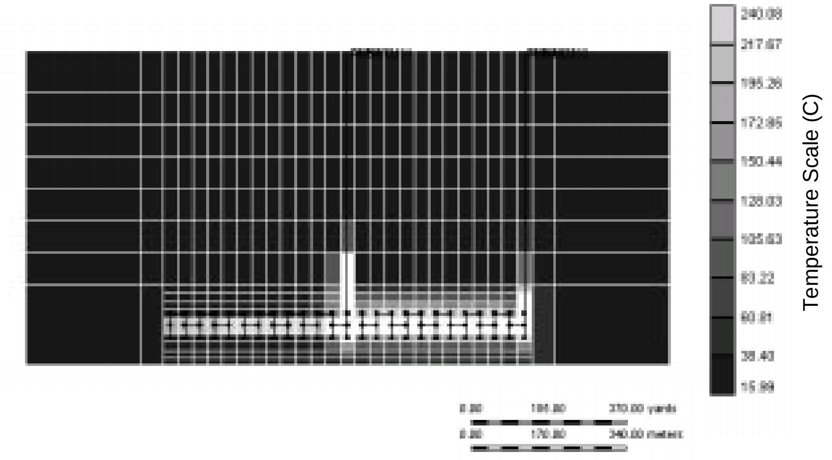

Fig. 8 - Temperature Profile at 100 Days, Case 1 – Continuous SAGD

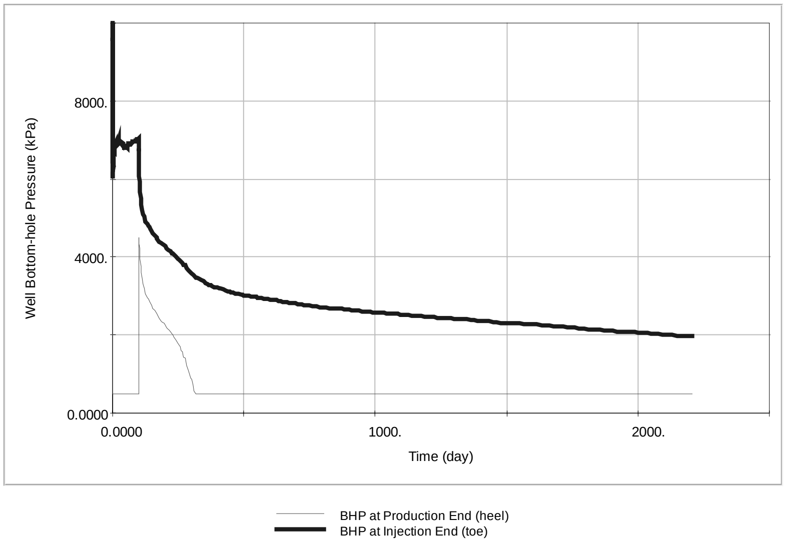

Fig. 9 - Well BHP vs. Time

Case 2, Extreme Pressure Differential, then SAGD

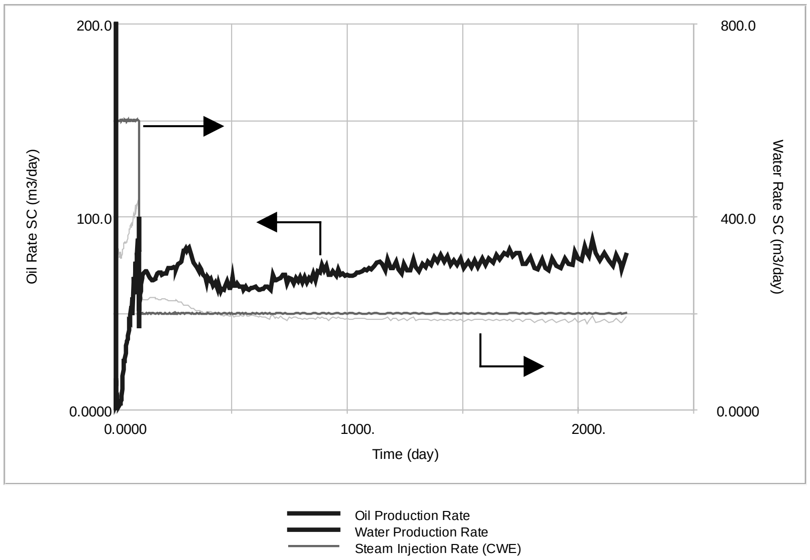

Fig. 10 - Production & Injection Rates vs. Time

Case 2, Extreme Pressure Differential, then SAGD

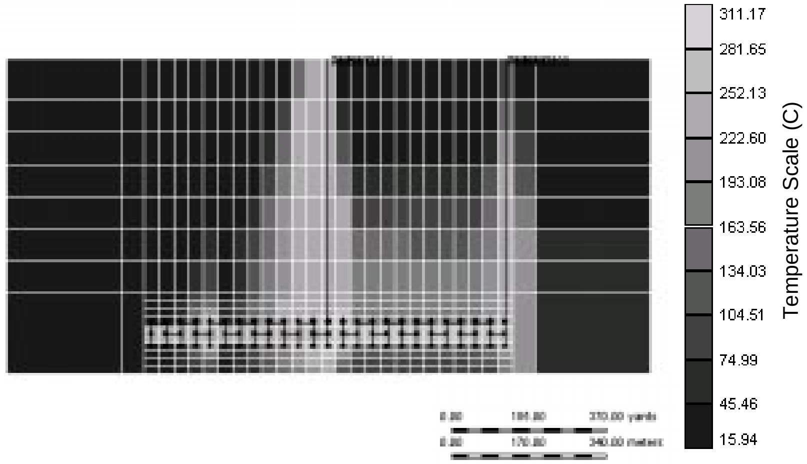

Fig. 11 - Temperature Profile at 200 Days (100 Days after SAGD began), Case 2 – Extreme Pressure Differential, then SAGD

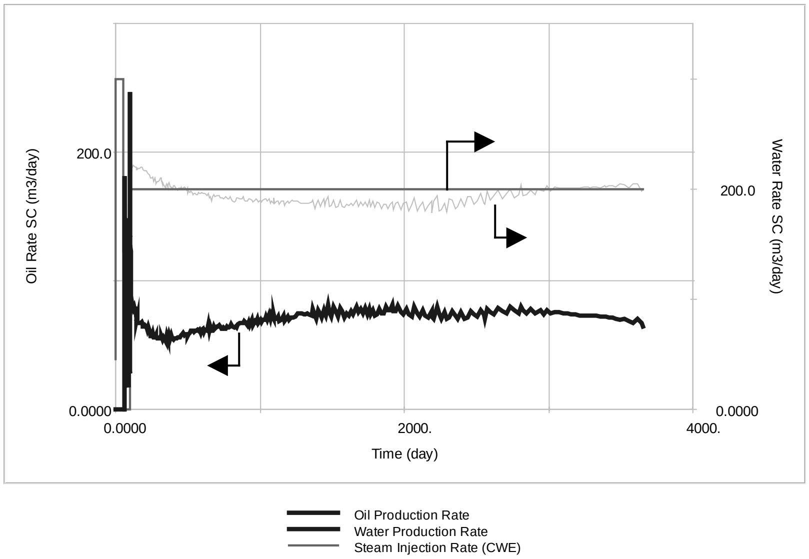

Fig. 12 - Production & Injection Rates vs. Time

Case 5, Cycle 1X, then SAGD

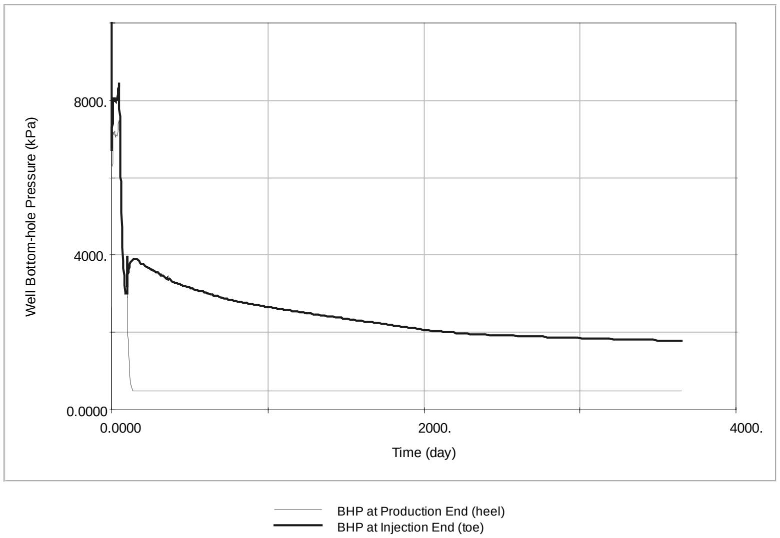

Fig. 13 - Well BHP vs. Time

Case 5, Cycle 1X, then SAGD

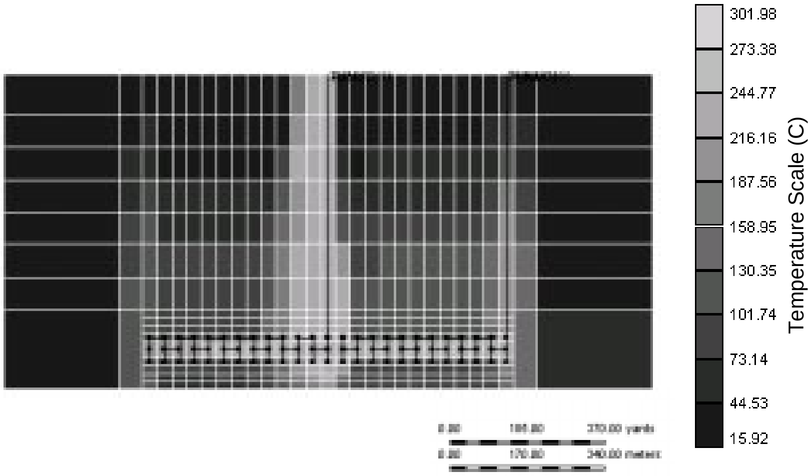

Fig. 14 - Temperature Profile at 300 Days (120 Days after SAGD began), Case 5 – Cycle 1X, then SAGD